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EVALUATION OF THE SHO-VEL-TUM ALKALI-SURFACTANT-POLYMER (ASP) OIL RECOVERY PROJECT – STEPHENS COUNTY, OK

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By
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Troy French

Abstract

Le Norman Energy Company is conducting research on field application of alkaline-surfactant-polymer (ASP) flooding as a part of the U. S. Department of Energy's plan to maximize the production of our domestic oil resources. In addition to having substantial technical merit, the process uses chemicals that are environmentally acceptable. Le Norman's field project is located in the Sho-Vel-Tum (OK) oil field, which was a major producer of crude oil in past years, but has since been extensively waterflooded. This reservoir in this portion of the field is typical of many shallow reservoirs in the Oklahoma-Kansas area and is a good demonstration site for that area. The pay zones are located approximately 700 ft. deep, and this project is the shallowest field test for ASP flooding.

Before the project, the four pattern production wells were producing a total of about four barrels of oil per day. These wells were placed on production more than 40 years ago, and this production rate of a barrel per day per well is typical of many reservoirs that have been waterflooded for many years. Based on laboratory experiments, field equipment was designed and fabricated for the field injection facility. After tracer tests, plant completion, and pre-project production monitoring, injection of alkaline chemicals began in February of 1998. Pattern oil production began to respond to the injection of ASP in late April, and the production rate increased to 26 barrels per day before beginning to decline. By May of 1999, the production rate had decreased to about 6 barrels per day and was projected to return to near baseline level after a few more months of production. The total amount of incremental oil currently attributed to Le Norman's project is 10,444 barrels of crude oil.

Introduction

Many oil field operators find it increasingly difficult to economically recover substantial amounts of oil from U.S. fields. As fields mature, production rates eventually become uneconomic. This occurs despite the fact that a large fraction of the original oil resource yet remains in U.S. oil fields. Le Norman Energy Company, TRW Petroleum Technologies, and the

U.S. Department of Energy (DOE) have conducted research on field application of ASP (alkali/surfactant/polymer) flooding as a part of the DOE plan to maximize the economic producibility of our domestic oil resource. This research effort culminated with a field pilot test of the process at Le Norman's Warden Unit in the Sho-Vel-Tum oil field in southern Oklahoma. The pilot experiment was conducted in a shallow, fluvial reservoir that is typical of many mid-continent reservoirs.

ASP flooding continues to show promise of being cost-effective because alkali, in addition to reinforcing the activity of surfactants, reduces the depletion of surfactant and polymer that occurs due to retention in the reservoir. Prior to this test, the field viability of surfactant-enhanced alkaline flooding had been given a substantial boost by a small number of successful field experiments conducted in the United States (Clark et al. 1988; Falls et al. 1992; Meyers et al. 1992).

Research and field experience have shown that surfactant-enhanced alkaline field floods that are properly designed with weak alkali and a polymer (for mobility control) can be effective for reducing residual oil saturation and for increasing the rate of oil production. Near-term application of this promising IOR technology was consistent with the Department of Energy's oil research strategy. The benefits of conducting this project include information and data that helps to demonstrate the applicability of surfactant-enhanced alkaline flooding as a cost-effective IOR method, transfer of surfactant-enhanced alkaline flooding technology to the petroleum industry, and information regarding procedures for designing and applying this technology that will assist independent producers in sustaining production from mature oil fields rather than abandoning marginal wells.

Field Site

Project location, shown in Figure 1 (Appendix A), is 16 mi. east of Duncan, OK in the Sho-Vel-Tum oil field. Production is from two Permian sands at depths of 677 ft and 705 ft. The pattern injection well is located at the center of a 2.5 Ac five-spot. Well locations are shown in Figure 2. Well ERI No. 1 is the pattern injection well and numbers 109, 110, 115, and 116 are the production wells. The other injection wells near the pattern area set up flow patterns in the area that help confine flow to the pattern area. The four production wells were steadily producing a total of about 4 bbl/day of oil when the project began (French et al. 1998).

Produced oil from the unit is moderately heavy crude. Oil gravity is 26.4° API, and in-situ oil viscosity is 41.3 cP at 30°C reservoir temperature. Oil acid number is 0.28 mg KOH/g oil, which is favorable to alkaline flooding. Reservoir salinity is quite low, which is also favorable. The low reservoir salinity is due, at least partially, to many years of waterflooding with fresh water.

Description of Reservoir (Lithology and Structure)

Well ERI No. 1 was drilled and cored in December 1997. The stratigraphic intervals encountered in the project are the Pennsylvanian and Permian Pototoc Groups; i.e. Upper Virgilian and Wolfcampian age. These deposits were laid down between two large southern Oklahoma basins, the Anadarko and Arkoma. These areas acted as large depocenters during the late Pennsylvanian and lower Permian with sediment supplied from the Wichita and Arbuckle Mountains. These two uplifts, active during the Pennsylvanian, supplied the sediment for the fluvial dominated red beds characteristic of the late Pennsylvanian and Permian in southern Oklahoma. More recent structural development of the Velma Field area was from a pair of northwest-southeast anticlinal structures assisting the trapping of hydrocarbons.

The dominant depositional environment represented in the ERI No. 1 core is basal fluvial. Lithologically, these deposits are light to dark brown, very fine to medium and coarse-grained quartz arenites to sublitharanenites. Quartz sand comprises the majority of the grain components reflecting a high energy, continuously reworked depositional setting. The sediment is texturally mature, represented by well-sorted and rounded grains. There is an overall fining upward within the sand package, more coarse grained material at the base while finer grained material is present at the top, a diagnostic characteristic of fluvial deposits. Bedding is thin to medium (inches to feet thick), separated by layers of shale disrupting the continuity of sand bodies. Sedimentary structures present are both small and large scale cross-stratification. Larger scale cross-stratification is common at the base while small-scale features are found at the top. An additional sedimentary feature that is diagnostic of fluvial deposition found in this core is lag material at the base of the thick sand deposits. The lag material ranges up to 1.5 inches and is found only in the basal few feet of the thick sand deposits. There is oil staining throughout the fluvial channel deposits, but the staining is not continuous. There are variations in the concentration of stain relating to bed boundaries and to forset boundaries. These two bounding features dictate the presence or absence of oil stains, acting as impermeable layers within the sand bodies. On the finer scale, there is also an alternation of oil stain seen in subsequent forsets. This fluctuation in oil concentration is over a 0.1-inch scale. The reason for this variation is the subtle difference in grain size from base to top in individual foresets. Foreset tops, the finest grained material, act as impermeable barriers to flow impeding rapid fluid migration from forset to forset. This degree of variability indicates that this fluvial system is highly heterogeneous.

The lithology constituting the distributary channel deposits is quite similar to that of the fluvial channel deposits. Here again, quartz arenite and sublitharenite are the dominant lithologies, and texturally, the sediment is mature, well-sorted and rounded. The identification of this separate depositional unit is based on the lack of vertical continuity within the fluvial channel deposits. A significant break in deposition, thin shale (inches thick), segregates the fluvial channel deposit from the typically thinner compositionally similar distributary channel. These deposits are much thinner than the fluvial channel, 4 to 5 feet in thickness compared to the 20-foot thick fluvial channels. Not only are the deposits thinner vertically, but also by definition would be less widely distributed than the fluvial channels.

Crevasse splay deposits are identified in the ERI No. 1 core by relatively massive, approximately 3 ft thick sand beds. The lithology is fine grained quartz arenite with abundant organic material. Only minor planar stratification exists. These deposits were deposited during flood stages. As a river breached the banks, and sufficient energy continued, lobate, homogeneous sand bodies were laid down on the laterally adjacent floodplain. The sand beds are nearly homogeneous, but spatially they are probably extremely restricted.

The floodplain is represented by white to light gray, sandy silt. The significant decrease in grain size indicates that there is a pronounced decrease in energy associated with this environment and the fluvial channel environments previously discussed. There is a weak planar lamination in the basal portions of this facies, indicating a gradation from the underlying fluvial deposits and these sandy silts. Additionally, the basal planar lamination is disrupted by bioturbation, probably from burrowing plant roots. The gradation indicates that the two environments were laterally contiguous further justifying the facies interpretation. Another feature that suggests floodplain deposits is the presence of organic matter, in the form of carbonized plant material. Typically, floodplain deposits are friable, but here there is evidence of vertical fracturing. The lithologic strength may be due to diagenetic alteration that, accompanied with stress applied to this unit, caused the fracturing present in the core sample.

Paleosol sediments are easily recognized by the grain size and composition and the textural features. The lithology is a silty shale, and is gradational with the underlying floodplain deposits. The lithology is variegated with the characteristic red iron color of paleosols, and indication of oxic sediment alteration. This single feature, along with gradational contact with the foodplain are the distinguishing features of this depositional facies.

Overall, the ERI No. 1 core consists of two fluvial successions. Each channel succession contains a basal fluvial channel grading upward into the finer grained, lower energy environments of the floodplain and paleosol environments. The vertical thickness of the two fluvial successions indicates that the original fluvial environments were relatively small, less than 20 feet in depth. These deposits are very characteristic of depositional conditions in the Pennsylvanian and Permian of the mid-continent region (Jordan, 1998).

Sand Body Correlation

A correlation of the wells in the chemical flood project area was performed. The cross-section is a northwest to southeast correlation of wells based on the well log signatures of either gamma or SP curves. The detailed core description proved valuable in the correlation, due partly to the fact that there is a high degree of heterogeneity found in these fluvial deposits. A broad-based correlation between wells is present at 700-foot depth and at 740-ft depth. These two depths mark the base of Permian sands 5 and 6. Smaller scale features were identified in the correlation, the crevasse splay deposits found in ERI No. 1 core. Two other crevasse splay deposits were tentatively identified in the No. 136 well, both occurring at the top portion of the fluvial succession. It is important to note that these crevasse splay deposits represent significant sands within one well, but are not laterally continuous, adding to the heterogeneity in these fluvial deposits.

The most obvious feature within the thick correlated packages, Permian 5 and 6 sands, is the variability seen in the gamma and SP log signatures. This indicates that not only is the vertical thickness of the sands variable from well to well, but the number and vertical distribution of sands varies between wells.

An example of the internal variability of the reservoirs is seen in the Permian 5 sand, a unit between 650 feet and 700 feet that could be correlated between wells. There is a distinct difference in sand body geometry from well 135 to well 109 to well ERI No. 1 and to well 116. The identifiable sands in this larger sand unit vary from 1 to 3 at the various wells. It is probable that the actual variability at locations between wells is even greater. This variability has important ramification on the interconnectedness of sand bodies between wells in the pattern area. The thicker basal fluvial channel deposits are potentially consistent between wells, but thinner sands do not appear traceable from well to well. Along consistent depth horizons, similar sands may or may not be connected. Additional cores, which are not available, would be required to increase the confidence in terms of the correlation within and around the project area (Jordan, 1998).

Routine and Special Core Analyses

Approximately 58 ft of core was obtained from injection well ERI No. 1 with two 30-ft core barrels. Due to the friable nature of the sandstone, a special inner core barrel made of aluminum alloy was used. Considering the fragile nature of the sands, the 97% recovery of core was extremely good. Two feet of core were lost from the bottom of the second core due to drilling crew error. The core was removed from the site still in the two core barrels. After removal from the site, the core barrels were cut into 3 ft long sections, and each 3 ft section was capped with a neoprene end piece. The core was then examined with X-ray tomography while still in the core barrel sections. The cores were then removed from the core barrels and core plugs cut for the analytical procedures. The cores are from the Permian No. 5 and the Permian No. 6 sands. The Permian No. 5 (upper sand) was the primary target for the field project, but the Permian No. 6 (lower of the two sands) appeared to be the best candidate for a chemical flooding project. Routine core analytical results are given in Table 1.

The upper sand (Permian No. 5) consists of about 12 ft of very porous sandstone. Average current oil saturation was 32.6% PV of oil. Average permeability is about 300 mD. There was about 4.3% mobile oil as the ultimate residual from waterflooding was shown to be 28.3% PV.

Table 1. - Routine Core Analysis, Permian 5 and 6 Sands.

Depth, ft.	S_o, %PV	K, md		Depth, ft.	S_o, %PV	K, md
676	4	<1		701	3	imp.
677	11	3		702	2	1
678	38	148		703	2	<1
679	30	34		704	-	shale
680	44	2		705	-	shale
681	48	41		706	-	shale
682	32	252		707	-	shale
683	26	40		708	24	<1
684	37	437		709	46	60
685	30	63		710	42	381
686	34	24		711	39	54
687	42	4		712	42	465
688	30	182		713	41	178
689	33	501		714	49	602
690	37	412		715	37	68
691	33	1443		716	56	301
692	36	1245		717	46	978
693	29	1185		718	57	1790
694	36	126		719	55	3227
695	12	18		720	33	350
696	20	25		721	23	4
697	27	4		722	34	63
698	30	56		723	29	443
699	17	3		724	Bottom of core	
<u>Weighted Average (19 ft)</u>				<u>Weighted Average (15 ft)</u>		
S_o = 32.6 %PV				S_o = 41.9 %PV		
K = 300 md				K = 800 md		
S_{owf} = 28.3 %PV				S_{owf} = 26.9 %PV		

Oil saturation was considerably higher in the lower sand (Permian No. 6). Oil saturation there was about 41.9% PV. This means that there was about 15% PV of mobile oil since the ultimate waterflood potential of the No. 6 sand was shown to be down to an oil saturation of about 26.9% PV. Well logs indicated that this sand is probably about 10 ft in thickness.

Table 2 shows the relative abundance of minerals in the upper sand, which was the primary target for the project. Clay minerals analysis is important from several aspects (French and Burchfield 1990). The primary importance to this project is that they give an indication of reactivity to alkalis. There is 3% kaolinite in the sample, and this means that some reactivity to alkali is to be expected. The wettability of Warden core was also measured. Figures 3 and 4 are typical of the wettability measurements conducted with Warden core from well ERI No. 1. The core exhibits intermediate wettability which tends toward slightly oil-wet. A reservoir with intermediate wettability is usually considered more favorable for chemical flooding than a reservoir that is strongly oil-wet.

Table 2. - Core Mineral Analysis.

Mineral Constituents	Relative Abundance, %
Quartz	94
Plagioclase Feldspar	trc
K-Feldspar	trc
Dolomite	1
Siderite	trc
Kaolinite	3
Chlorite	trc
Illite/Mica	1
Mixed-Layer Illite/Smectite	1
% Illite layers in M.L. Illite/Smectite	45-55
TOTAL	100

Figure 5 shows an overall conception of the upper (Permian No. 5) reservoir in the vicinity of the injection well. The sand thicknesses in the illustration represent gross pay, rather than net pay. This conception is based on core analysis and well logs at the injection well and old well logs from the surrounding production wells. Remember that it is not possible to correlate individual sand lenses between wells. The major feature of the sand is that about 8 net feet of highly permeable sand (100 mD) is above a few feet more of even higher permeability sandstone (1300 mD). If one will examine the core analysis data for the lower (Permian No. 6) sand given in Table 1, it will be noticed that the structure of the lower sand is remarkably similar to the upper reservoir. The main difference is that the lower sandstone reservoir contains sand layers that have even higher permeabilities.

Figure 6 shows a computer generated CT topogram that is representative of the layered structure in the upper sand. The major feature of the topogram is the complexity of the layering of the sand. The complexity of the fining-up sequences, as previously stated, is typical of many mid-continent, fluvial reservoirs.

All of the data from well logs and core analyses indicate these Permian sands are reasonably good candidates for ASP flooding. The reservoir was also shown to be typical of many shallow mid-continent oil reservoirs. As was described above, the two sands are separated by a shale/clay layer. Since it is doubtful that the shale/clay layer is sealing, especially in the near well bore region, both sands as a unit became the target zone for the chemical flood. Additionally, injection profile tests indicated communication near the well bore in the zone between the Permian 5 and 6 sands.

Core-Alkali-Surfactant Chemistry

Clay minerals analysis is important for ASP projects from several aspects. The primary importance to this project is that they give an indication of reactivity to alkalis. X-ray diffraction analysis, which was given in Table 2, indicated the presence of 3% kaolinite, and this means that some reactivity to alkali was to be expected (French and Burchfield, 1990).

Figure 7 shows the results of long-term measurements between alkali and crushed field core. The experiment was conducted with 0.010 N Na_2CO_3 (sodium carbonate). The aqueous Na_2CO_3 solution was contacted with clean crushed reservoir core at a 5:1 liquid/solid ratio. Samples were agitated periodically during the 40 day time period. Since it is known that aqueous mixtures in contact with sandstone core material can acquire a small amount of alkalinity from the sandstone, equivalent samples containing only NaCl and crushed core were also monitored. Over the time period, pH decreased by about 0.2 pH units. Total alkalinity of the samples actually increased. The increase in alkalinity was due to the effect of the sandstone described above, and corrected values for alkaline consumption are reflected in the curve in Figure 7 that is described as "total alkalinity less sand alkalinity". The actual loss of alkalinity due to reaction with sand over the 40 day interval was 0.003 meq/ml. The results indicated minimal loss of alkalinity due to reaction with reservoir rock, and that deposition of mineral scale at production wells should not be severe.

Adsorption of ORS-62™ surfactant onto cleaned, crushed field core was measured by agitating samples that contained crushed core and surfactant solutions, then measuring equilibrium surfactant concentration by 2-phase titration. The magnitude of surfactant adsorption varied from about 2.0 to 3.2 mg/g, depending on equilibrium surfactant concentration. This corresponds to a range from 4.7 to 7.6 meq/kg, which is relatively high. Actual adsorption in corefloods was about one tenth these values, but that is still high enough that it should not be expected that surfactant would propagate the entire distance between the injection well and the production wells (French and Burchfield 1990; French 1996; Peru 1989).

Chemical System Design

Dynamic interfacial tension (IFT) was measured between Warden produced oil and several commercial surfactants using a spinning drop interfacial tensiometer. IFT measurements were recorded several times for 30 minutes after contacting the oil and surfactant mixture. The data from IFT experiments were compared with observations from phase behavior tests, which were conducted by mixing equal volumes of alkaline surfactant mixtures and Warden crude oil. Alkaline surfactant mixtures that contain relatively low surfactant concentrations typically do not solubilize a large amount of oil, rather forming temporary macro-emulsions. Therefore, the primary evaluation of the phase behavior tests was based on the emulsification observed during agitation and during the time interval shortly after agitation. Very low IFT is usually indicated by brown-chocolate color emulsions that slowly coalesce after agitation (French and Burchfield 1990).

All of the alkaline surfactant mixtures were formulated in rural water which was to be used for the field test chemical mixtures. Surfactant concentrations given in this report represent actual (active) concentration of the surfactant in the mixtures. For example, if a commercial surfactant was 50% active, it required 2g of bulk surfactant in 100g to produce 1% surfactant concentration. Initially, sodium tripolyphosphate (STPP) was added to chemical formulations to control precipitation due to hardness ions in the rural water. Eventually, the use of STPP was discontinued in favor of softened water. Elimination of precipitation at the injection plant reduced the maintenance time for filtration systems.

After preliminary screening, Witco-2094™, Witco-HL™, ORS-41™, and ORS-62™ surfactants were selected for further testing. The optimum Na_2CO_3 concentration between the surfactants and Warden oil was usually above 2 % Na_2CO_3, which is on the high side for good economics during a field test. The IFT between alkaline mixtures that contained 0.50% ORS-62 and Warden oil are shown in Figure 8. IFT values were measured as low as 2 X 10^{-5} mN/m for 2.20% Na_2CO_3 concentration. IFT values in this range are very favorable for mobilization of residual oil. Phase behavior observations also indicated optimum 2.20% Na_2CO_3 concentration.

During propagation through an oil reservoir, the chemical slug will be diluted by contact with formation brine. Experiments were therefore performed to determine the effect of dilution on IFT. Relatively low IFT values were measured even after the alkaline surfactant was greatly diluted by reservoir brine. IFT values did not increase to 10^{-2} mN/m until after surfactant concentration was diluted to less than 0.20% concentration. Overall, ORS-62 was the most promising for use in the Warden pilot test. Part of the consideration was that the low viscosity of the ORS surfactant allows the surfactant to be pumped without heating.

Since Warden oil gravity is 26.4° API gravity with in-situ viscosity of 41.3 cP, a relatively high molecular weight polymer is needed to propagate an oil bank through the reservoir. Allied Colloids 1275A™ partially hydrolyzed polyacrylamide polymer was selected. Figure 9 shows the viscosities of polymer mixtures that were injected during the field test. The ASP mixture contained 2.20% Na_2CO_3, 0.5% surfactant, and 1000 ppm polymer in softened rural water. The viscosity of this mixture at reservoir shear rate was 14.0 cP. The ASP mixture was stable, with some phase separation occurring over time. The viscosity of samples of the ASP mixture actually increased slightly after aging for one month. The viscosity of the polymer in the chase mixture that contained only 1000 ppm polymer in softened rural water was 48.0 cP, providing a very favorable mobility ratio with Warden oil. During the field test, the polymer concentration was tapered (gradually reduced) to 600 ppm during the post-ASP mobility buffer injection.

Corefloods performed in Berea and field cores showed that the chemical system could recover substantial oil. Figure 10 shows the core oil saturations after waterflooding and subsequent ASP flooding using several surfactants made up in 2.20% Na_2CO_3, plus 1000 ppm Alcoflood 1275A polymer mixed in injection (rural) water The X-abscissa in Figure 10 is the product of surfactant concentration and slug size. In each flood, the ASP mixture was preceded by a small alkaline preflush and followed with 1000 ppm chase polymer. The floods with ORS-62 surfactant recovered the most oil. The series of floods with ORS-62 surfactant was the only series of floods which reduced residual oil saturation to less than 8%. The flood performed with 0.19 PV of ASP mixture performed equally as well as injection of a larger ASP slug. Results indicated that residual oil saturations near 12% PV were possible for the field test if relatively large volumes of chemicals were injected.

Field Tracer Tests and Computer Simulations

Computer simulation was used to predict and match the results of laboratory corefloods and field tracer tests, as well as to predict pattern oil recovery. Figure 11 shows a comparison of laboratory coreflood oil production and computer simulation. For this comparison, the computer model consisted of only one layer due to the fact that the core plugs used for oil recovery tests were relatively homogeneous. Other model parameters were representative of the Permian 5 reservoir and the properties of the ASP chemical mixture. Agreement between the computer model and the core flood are good. The model was surprisingly sensitive to core porosity, but the indications are that good oil recovery can be achieved with 0.30 PV of ASP injection.

Field tracer tests were performed using IPA (isopropanol) to detect fractures and NaSCN (sodium thiocyanate) to follow flow through matrix. The results of these laboratory and field measurements were incorporated into chemical flooding computer simulation software and several injection scenarios were simulated. Figure 12 shows the concentrations of NaSCN measured at the four production wells. Historically, well 116 produced small amounts of fluid when compared with the other 3 production wells. Rework and acid treatments failed to improve the production rate and therefore, as shown in Figure 11, only small amounts of tracer were detected at well 116. The largest amount of tracer was produced from well 115, indicating preferential flow in that direction, and wells 109 and 110 produced intermediate amounts of tracer. Overall, the tracer tests indicated directional permeability, but no flow through fractures.

These data were incorporated into the chemical flood model and the simulation shown in Figure 13 matched the field tracer results quite well.

As described above, injection profile tests indicated that it would not be possible to isolate zones for profile modification treatment. It was therefore decided not to attempt to improve the flow patterns because of the high risk of damaging the entire zone(s). The 3-layer simulation model was then used to predict oil recovery from the pattern area. This prediction for injection of 0.10 PV alkaline preflush containing 2.2% Na_2CO_3, 0.30 PV ASP containing 2.2% Na_2CO_3 and 0.50% ORS-62, followed with 0.50 PV of polymer containing 1000 ppm of 1275A polymer is shown in Figure 14. As will be shown subsequently in this report, the total amount of oil produced by the project approached simulation predictions, but the rate of oil production proved to be lower than was predicted.

Design and Operation of the Field Injection Facility

Since there have been many inquires concerning the design and operation of the injection facility, the primary equipment items in the injection plant are shown in Figure 15. The total fluid flow to the injection well is 285 bbl/day for this project, which is determined by the capacity and operational speed of the main injection pump. Softened water enters the mix tanks through float valves at the same rate as it is discharged. Therefore, the water level in the mix tanks is constant. Sodium carbonate is delivered from the storage silo to the main mix tank through a variable speed auger. The sodium carbonate delivery rate is 2,174 lb/day. A metering pump is used to deliver surfactant at a rate of 600 ml/min to the surfactant mix tank, which corresponds to 494 active lb/day of surfactant. Diluted surfactant is then pumped to the main mix tank by a second metering pump, where it is further diluted as it mixes with sodium carbonate. The mixture of sodium carbonate and surfactant is pumped through 5 micron filters with a centrifugal pump. After the 5 micron filter, the surfactant/carbonate stream mixes with the polymer unit stream and the combined alkali/surfactant/polymer stream then passes through a 25 micron filter unit. Solid polymer is metered into the Minifab™ polymer unit through a small auger at a rate of 99 lb/day. The polymer stream concentration is 3535 ppm of polymer. The polymer stream is regulated to 80 bbl/day with a Moyno™ low shear polymer pump (metering unit). The fluid passing through the main injection pump contains 0.5% active surfactant, 2.20% sodium carbonate, and 1000 ppm polymer. After the main injection pump, the combined fluid stream passes through an in-line mixer and to the injection well. For safety, the mix tanks are equipped with high/low sensors, which will shut down the entire plant in the event that the water supply should fail or a mix tank was overfilled. This safety system also includes an automatic shut-off valve in the surfactant supply line.

Project Monitoring, Results and Evaluation

In general, project monitoring time periods are based on the timeline that was shown on the X-abscissa in Figure 14. Day 0 in that figure corresponds to the start of alkaline preflush. As an exception, however, it was more convenient to plot some graphs, especially those relating to pre-project base-line data, with different timelines. When the beginning of timelines is other than the start of alkaline preflush, it will be so stated in the discussions for those figures. In a few cases, graphs are plotted with the X-abscissa expressed as the amount (pore volumes) of fluid injected. Injection times and pore volumes are very closely related, with 1.0 PV corresponding to approximately 160 days of injection time. This relationship is not exact, however, because plant down-time did not occur at a constant rate throughout the project.

In addition to monitoring oil production, tests were conducted periodically at each production well to determine whether polymer was present in produced fluids. Results from polymer detection tests and other significant operational events are noted in Figure 16. Polymer was detected first at production well 115, and much later at wells 109 and 110. Only trace amounts of polymer were ever detected at well 116. This order of detection corresponds very well with predictions based on field tracer tests.

Response from chemical injection occurred after injection of 0.6 PV (102 days) of fluids including the alkaline preflush. Peak oil production occurred 1.3 PV (214 days) after the start of preflush. Decrease in oil production correlated with the decrease in polymer concentrations at production wells 109, 110, and 115. By 2.4 PV, polymer concentration was less than 10 ppm at all three production wells.

Production well tests were performed periodically before, during, and after the ASP injection. The results of four of these tests are shown in Figure 17. The individual well tests are not reliable for calculating total production. However, percentage-wise there were large increases in the amounts of oil produced from pattern wells 109 and 115 as was predicted. It was not expected that oil production would increase much from production well 116. Figure 12 (tracer test) indicates that a response should also have been recorded at well 110 somewhat after response was observed at well 109. It is unknown why a more definitive production response form well 110 was not observed in the well tests.

Figure 18 shows oil production from the other 15 production wells in the Warden unit during the first two-month interval after oil production from these wells was separated from total unit production. Production from these 15 unit wells was nearly constant at a rate of 21 bbl/day over the two-month interval. Figure 19 shows a comparison of production from the four production wells in the ASP pattern and the other 15 unit production wells. There is a definite increase in the production rate from the 15 non-pattern wells that correlates with the increase in production from the four ASP pattern wells. In addition, production from the other 15 wells decreased to original production levels at nearly the same time that production from the ASP pattern decreased. Therefore, it appears that there was substantial response from the ASP project at other wells in the unit. The production from the other unit wells is co-mingled, but it is most likely that the increased production resulted from well numbers 114, 104, 126, and 106. Well numbers 112, 120, and 128 are unlikely to have responded, since they are somewhat isolated from the ASP pattern by fluids moving from injection well 117.

It is not considered unlikely that an increase in unit production could have resulted due to the ASP project. With only one ASP injection well in a heterogeneous reservoir, fluids likely would migrate from the pattern area to other production wells. Polymer detection tests at pattern wells indicated that fluids flowed preferentially in the direction of well 115 and never flowed in the direction of well 116. These results are in agreement with pre-ASP tracer surveys, and could indicate flow in the direction of wells 114 and 126. This flow pattern was, however, not confirmed by polymer detection tests at non-pattern wells.

Figure 20 compares the actual production and pre-project simulated production for the four pattern wells. Actual production is lagging behind predicted production both in amount and rate of production. This may be in part due to migration of fluids from the pattern area to other production wells in the unit. Production from the pattern area appears to be declining to pre-project levels at a rapid rate. Production from the pattern wells, through May of 1999, are shown in Figure 21. It appears that pattern production will decline to the pre-project level of about 4 bbl/day after approximately 4 PV of fluids have been injected.

Oil production from the project is summarized in Table 3. The total amount of oil attributed to the project is 10,444 bbl including 3,250 bbl off-pattern incremental and 108 bbl of incremental oil that is predicted to be produced before response ends. Total oil actually produced from the pattern area through May of 1999 was 8,275 bbl, which slightly exceeded the pre-project prediction of 8,000 bbl. However, the pattern oil was produced over a longer time interval and at a slower rate than was predicted. This is attributed to the fact, cited above, that well 110 did not respond to stimulation as soon as predicted.

Table 3. - Produced Oil Attributable to the Project.

Measured or predicted Oil	Amount of Oil, bbl
Pattern, actual project total	8,275
Pattern, actual ASP and post ASP	6,276
Pattern, simulation ASP and post ASP	8,000
Off-pattern incremental	3,250
Off-pattern incremental, adjusted	4,261
Total - ASP project, adjusted	12,536
Pattern, estimated w/o ASP project	2,200
Total from ASP project	10,336
Additional incremental projected	108
Total oil from ASP project, adjusted	10,444

The chemical costs for the project were $26,479 for 14,000 lb polymer, $25,479 for 47,980 lb (bulk) surfactant, and $14,854 for 73.3 ton soda ash. These represent total chemical prices, including shipping charges. The use of STPP was suspended when water softeners were placed in operation, and STPP costs were not included because STPP will not be used when the pilot project is enlarged. Another chemical cost that was not included was for isopropyl alcohol, which was needed to correct an unexpected problem (sodium sulfate precipitation) that occurred due to evaporation while the hot surfactant mixture was in transit. That problem can also be eliminated in future application of the process. The total chemical cost, including shipping charges, per incremental barrel of oil was equal to $67,017/10,444 bbl or $6.41/bbl incremental oil. This cost is not excessively high for a pilot experiment with one injection well in a heterogeneous reservoir. Some efficiency was lost due to migration of chemical fluids off-pattern, although a sizeable amount of incremental oil was produced off-pattern. The existing injection plant, with small modifications, is capable of output that will supply 4 injection wells. In that case, the cost per incremental barrel of oil should be nearer $4/bbl of incremental oil. The economics for shallow wells should be favorable for the process when the posted price of the oil is near $18 per barrel. The actual projected economics should be determined with an appropriate simulator before expanding the project.

Planned Activities

Four potential patterns for future projects were identified in the vicinity of the ASP project area. These four sites could be utilized for expansion of the ASP project or for conducting further field experiments with other technologies. Further evaluation of these sites is necessary before actually conducting additional oil recovery projects. It would be valuable to conduct a polymer flood on one of these sites. Direct comparison of a polymer flood with the ASP project would allow better evaluation of ASP technology in the unit.

Awards

The Warden unit is typical of many midcontinent reservoirs, and in April Le Norman Energy was notified that Oil and Gas World selected their project for Best of the Midcontinent New Technology project.

Conclusions and Recommendations

1. Oil production from pattern wells is projected to slightly exceed the amount that was predicted by computer simulation.

2. The oil production from pattern wells was produced at a slower rate and over a longer time-interval than was predicted.

3. The difference between predicted and actual oil production rates is due to an incomplete description of reservoir complexity.

4. Off-pattern incremental production due to the project is substantial.

5. The off-pattern incremental production indicates that reservoir sweep in this type of reservoir is probably poorer than was predicted, and could be improved by conducting an ASP project with at least four injectors, rather than only one injection well. This would probably also improve project economics.

6. Oil production is continuing at levels that are above pre-project levels, but the bulk of the project oil has been produced.

7. It will probably never be known how much of zone 6 was swept by the chemical slug. Since there was substantial and relatively rapid response at off-pattern wells, it is less likely that very much of the chemical slug traversed zone 6 and that most of the response was from zone 5.

8. Two field experiments are recommended that would prove invaluable in interpreting the results from this project. It would be valuable to compare with a polymer flood project in a similar region of the field, and with a project that was conducted after profile modification. The polymer flood would be considerably less expensive to conduct, and might result in considerable oil production (Russell 1988). (Polymer has been used with success in this region of the field before.)

9. Although potentially beneficial, profile modification was not attempted during this project because the risk of formation damage was considered too high. The results from this project indicate that if successful, profile modification treatment would have significantly improved reservoir sweep. When oil prices merit further investment, it is suggested that injection well ERI No. 1 be treated. This would provide better assessment of the risk of formation damage due to treatments in this unit, and would allow assessment of its beneficial effects. (Tracer surveys are, of course recommended.)

Acknowledgements

Many of my peers contributed to this project. I believe that several of them deserve special credit for their contributions. High on the list are Duane Le Norman and Dennis McPhail of Le Norman Energy Company. The project would not have been possible without the support of Dr. Jerry Casteel, DOE Project Officer. Plant operation would certainly have been chaotic without Mr. Wes Winslet of Le Norman Energy, who spent so many hours in the field, especially when we experienced unexpected problems while injecting STPP and surfactant. Chemists Kathy Bertus and Charles Josephson, formerly with TRW, deserve credit for their laboratory diligence. Mr. John Jordan, also a former TRW employee, deserves special credit for contributing most of the report sections on resesrvoir lithology and structure. Chuangen Zheng, another former TRW employee, contributed mightily to the reservoir simulations discussed in this report. Finally, my thanks to all of the others, especially my former supervisors at TRW, Dr. Rebecca Bryant and Dr. Thomas Burchfield, who worked many hours to make this project a reality.

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Appendix A.

Report Figures.

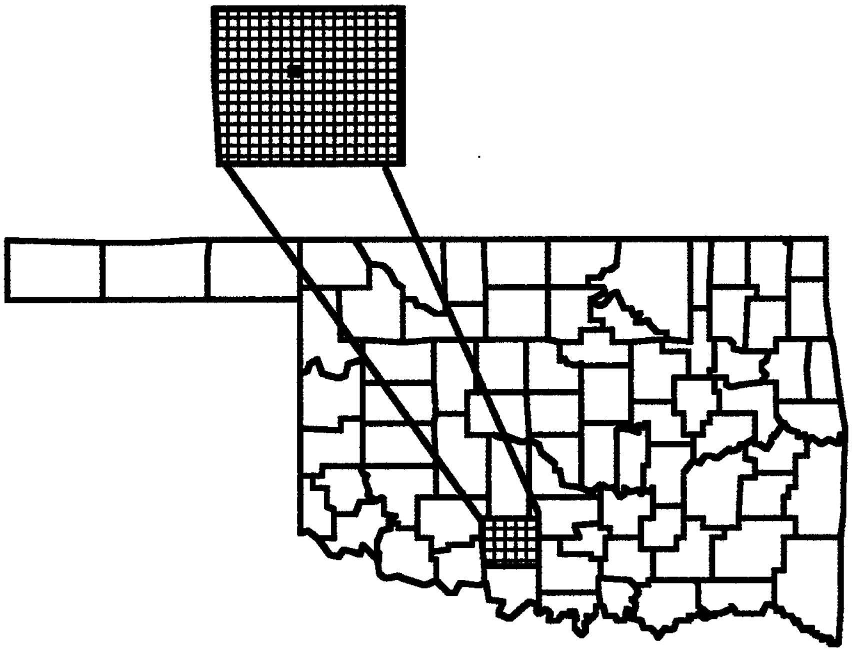

Figure 1. ASP Field Experiment in Sho-Vel-Tum Oil Field.

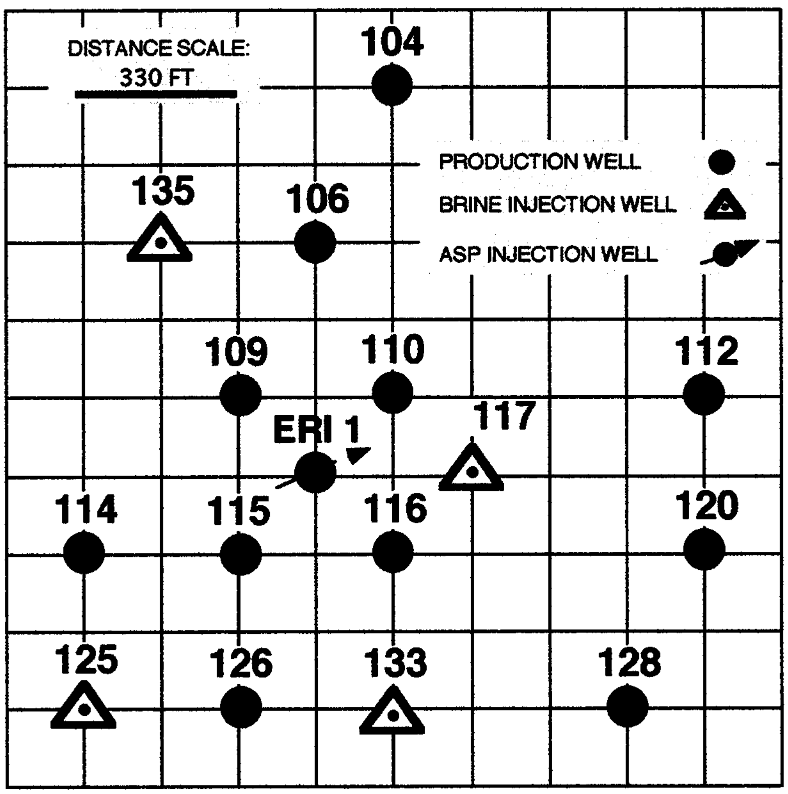

Figure 2. Field Experiment Well Pattern - 2.5-Acre Five-Spot.

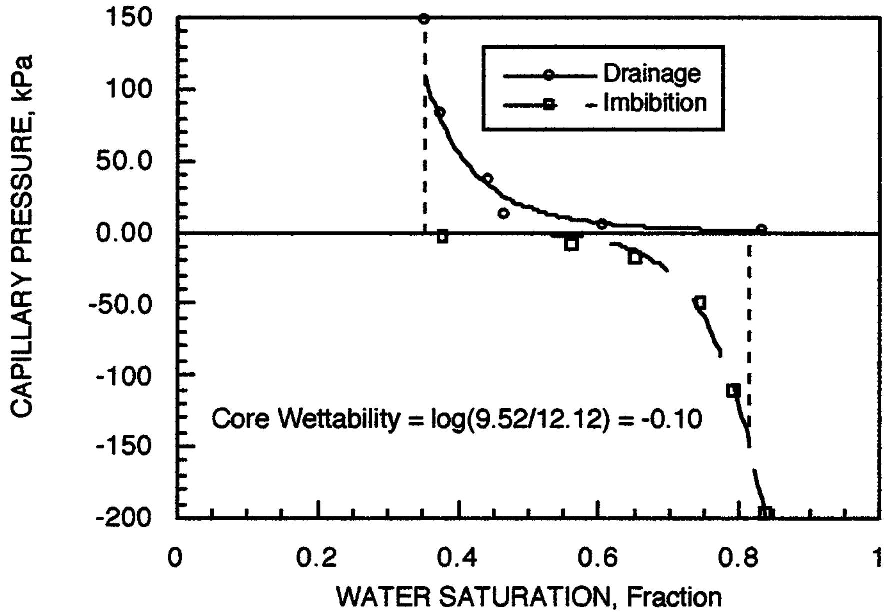

Figure 3. Warden Field Core Wettability - Core A

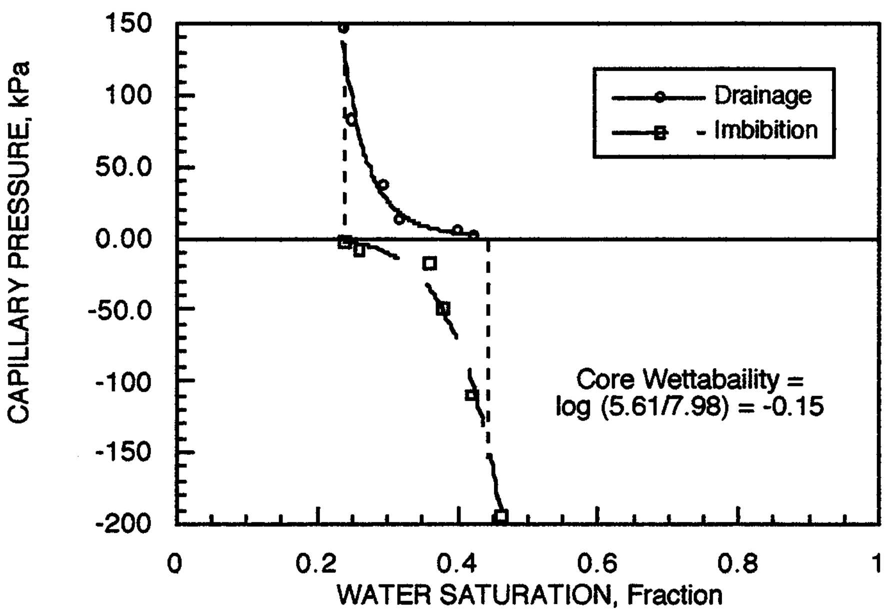

Figure 4. Warden Field Core Wettability - Core B.

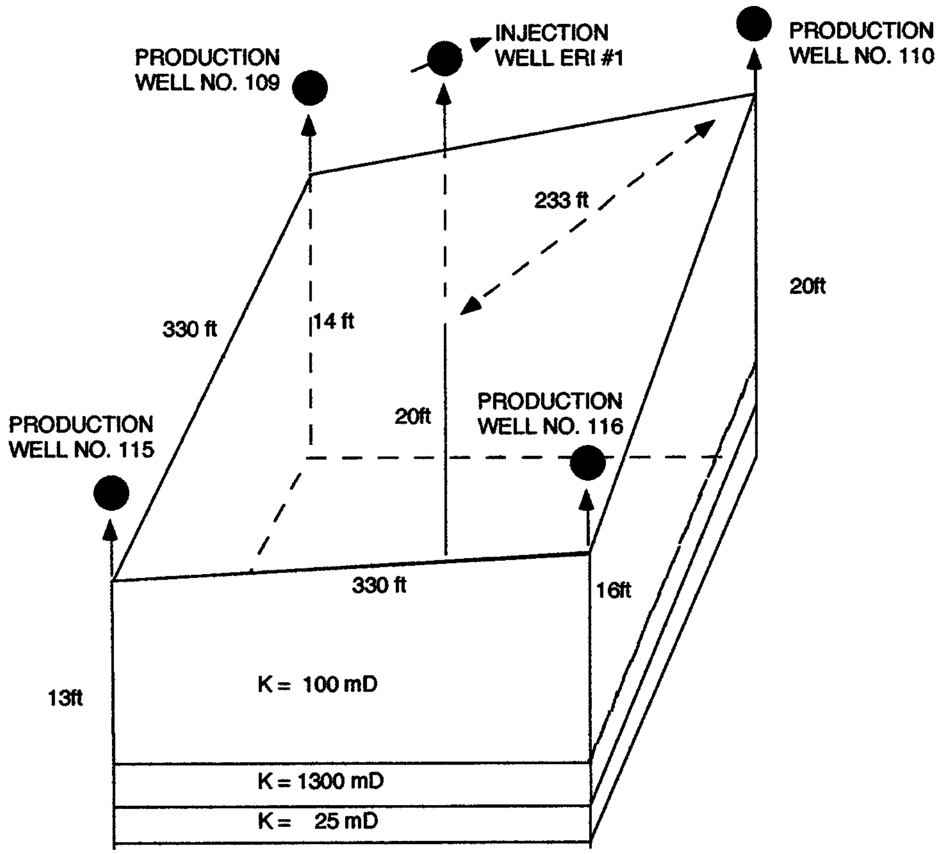

Figure 5. Conception of Permian 5 Sand from Well Log Correlation.

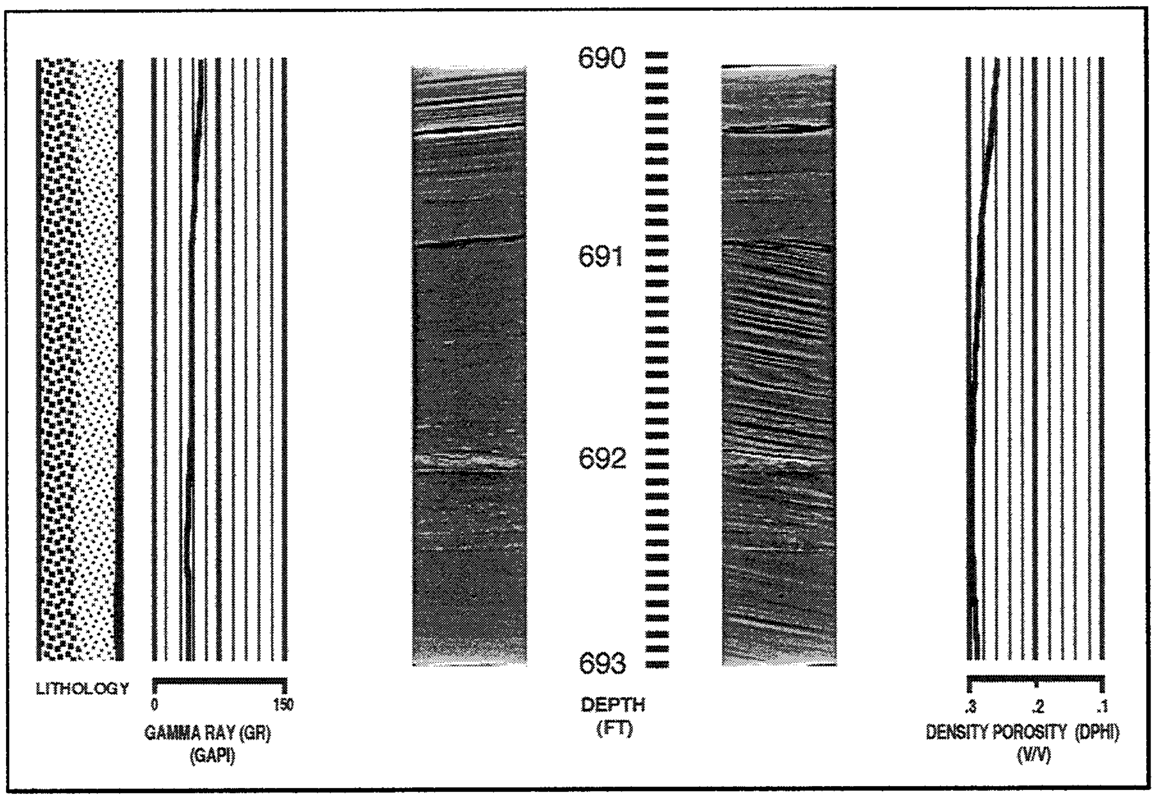

Figure 6. X-Ray Computed Tomography - Permian 5 Sand.

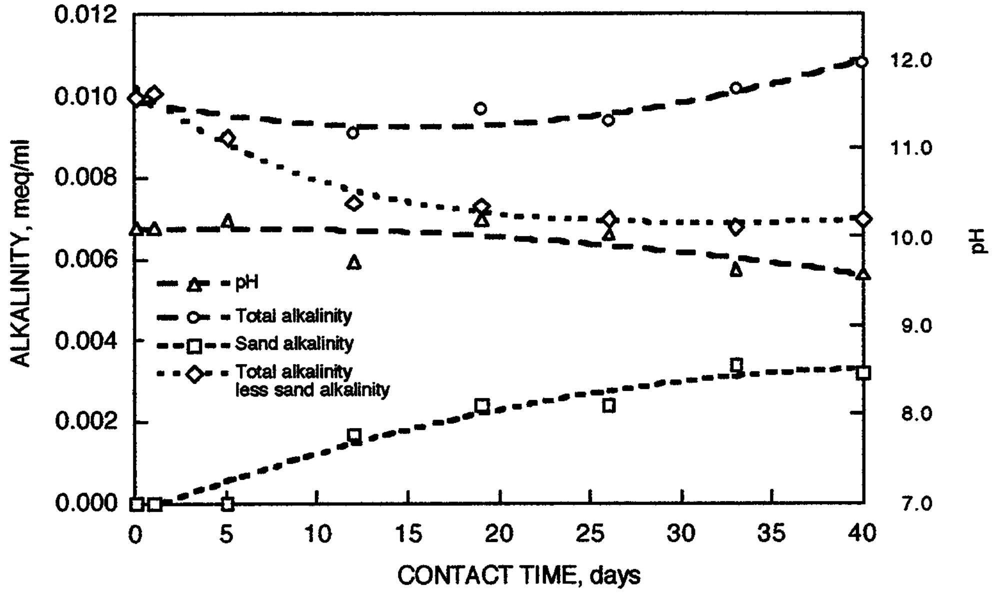

Figure 7. Alkali Consumption Measurements.

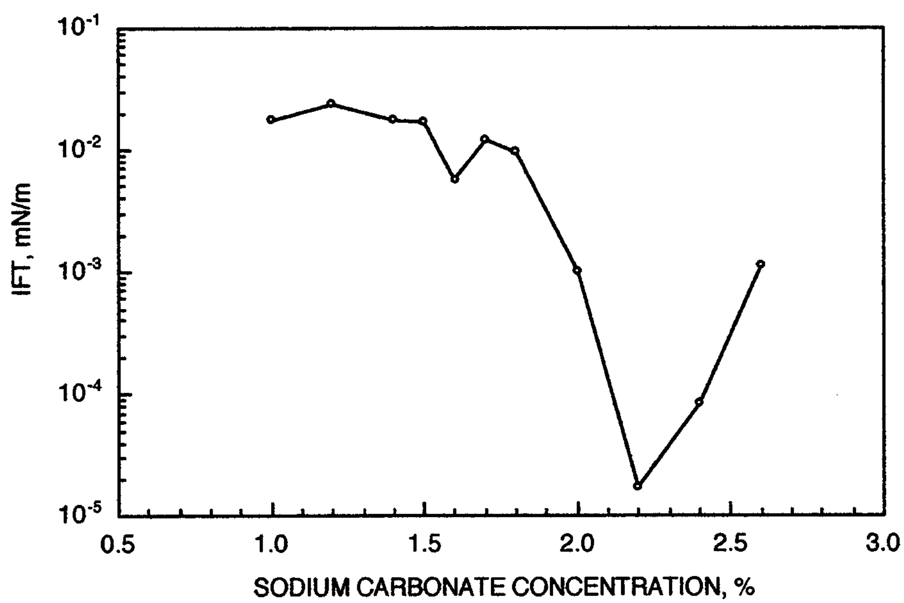

Figure 8. Interfacial Tension between Warden Oil and 0.5% ORS-62.

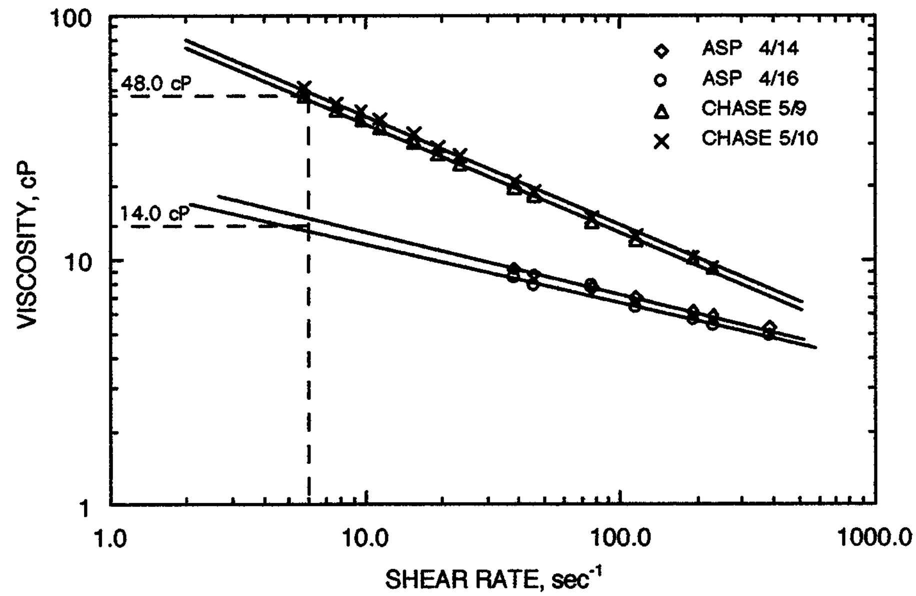

Figure 9. Injection Fluid Viscosities.

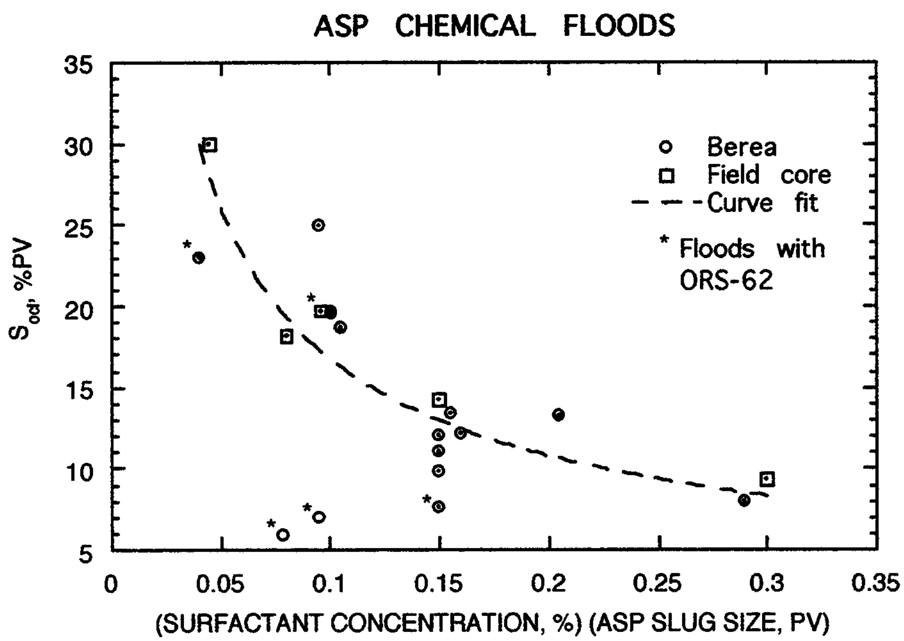

Figure 10. Laboratory Corefloods.

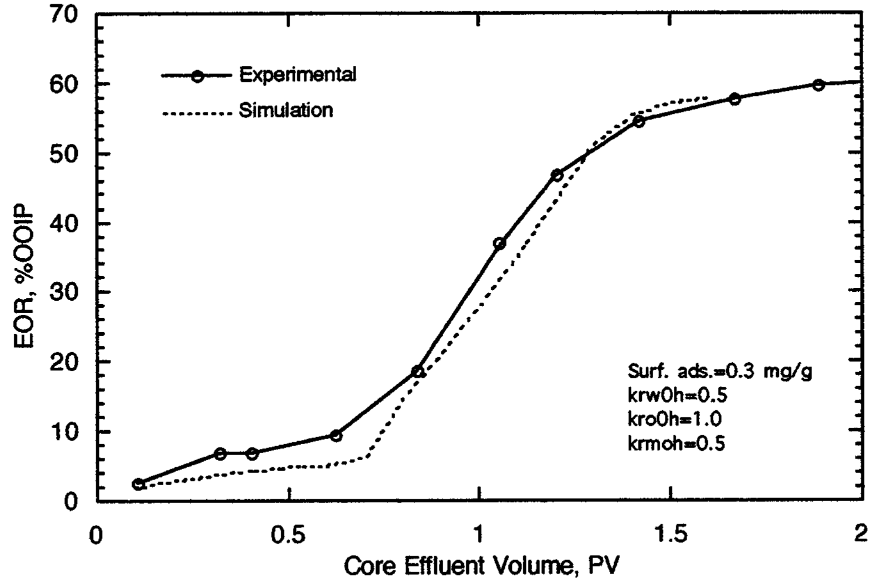

Figure 11. Computer Simulation of Coreflood.

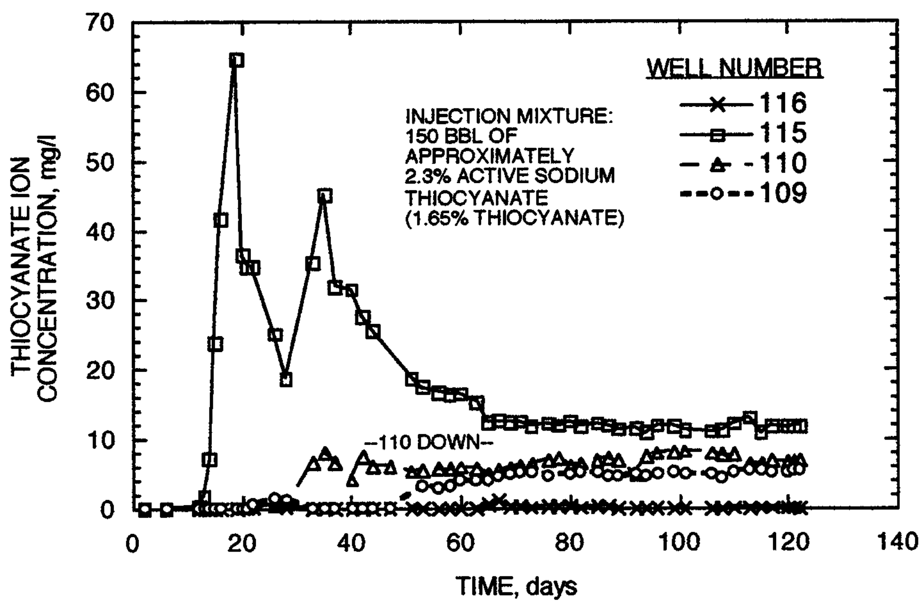

Figure 12. Field Tracer Test.

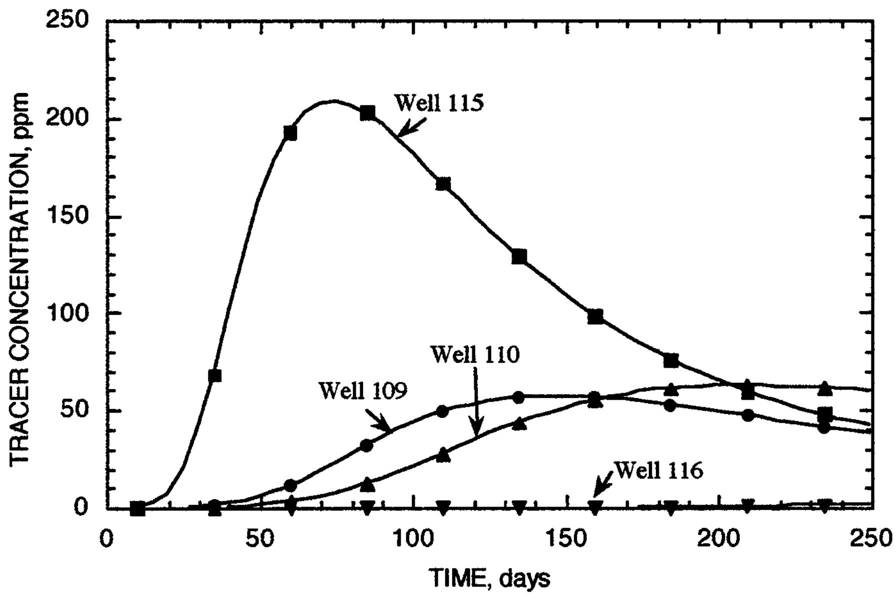

Figure 13. Computer Model Incorporating Field Data.

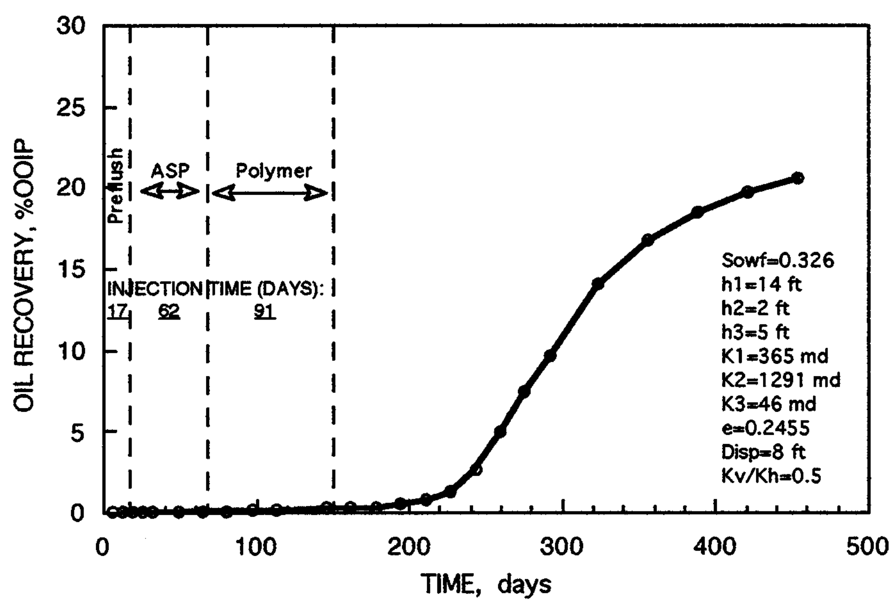

Figure 14. Predicted Oil Recovery.

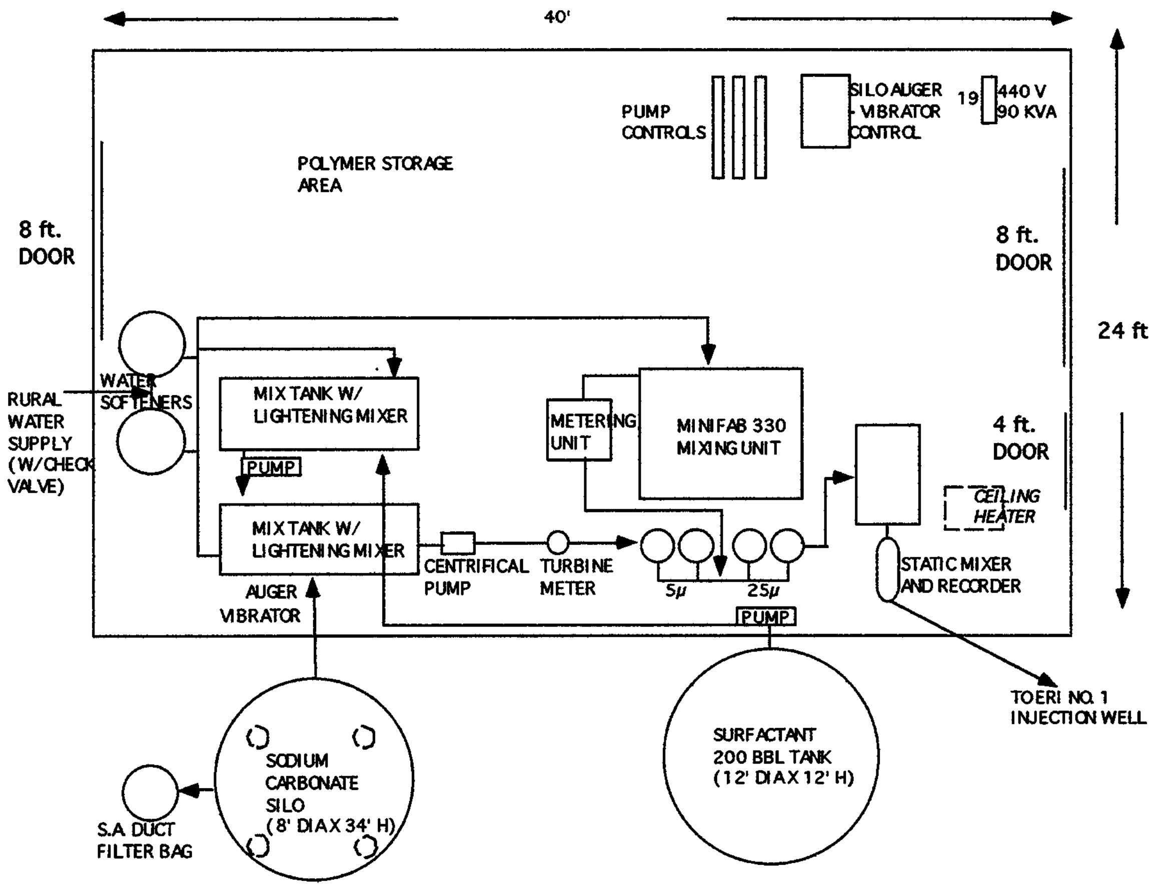

Figure 15. Field Injection Facility.

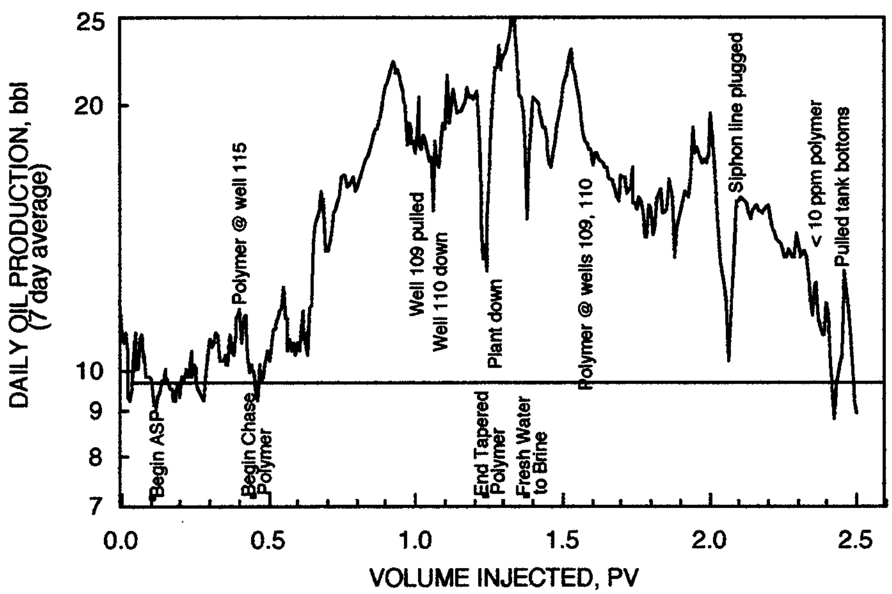

Figure 16. ASP Pattern Oil Production.

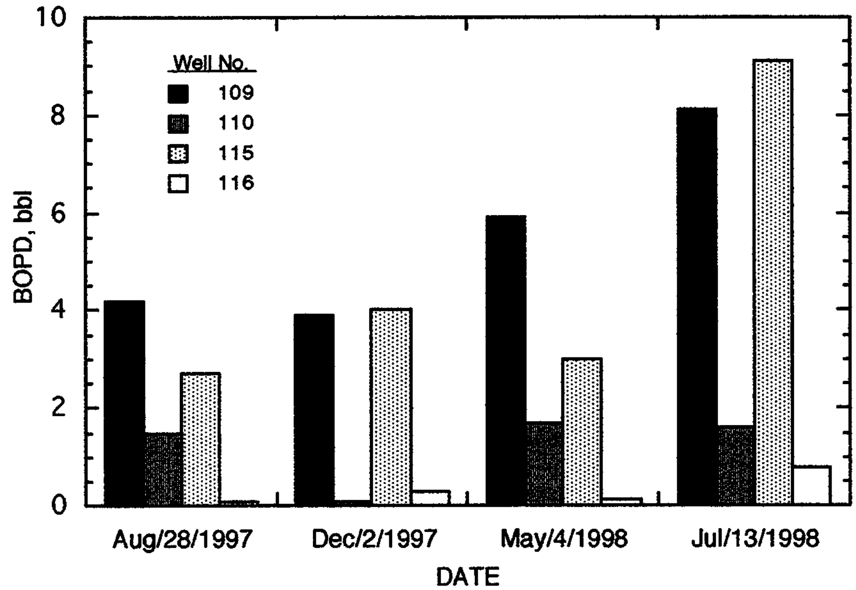

Figure 17. Pattern Production Well Tests.

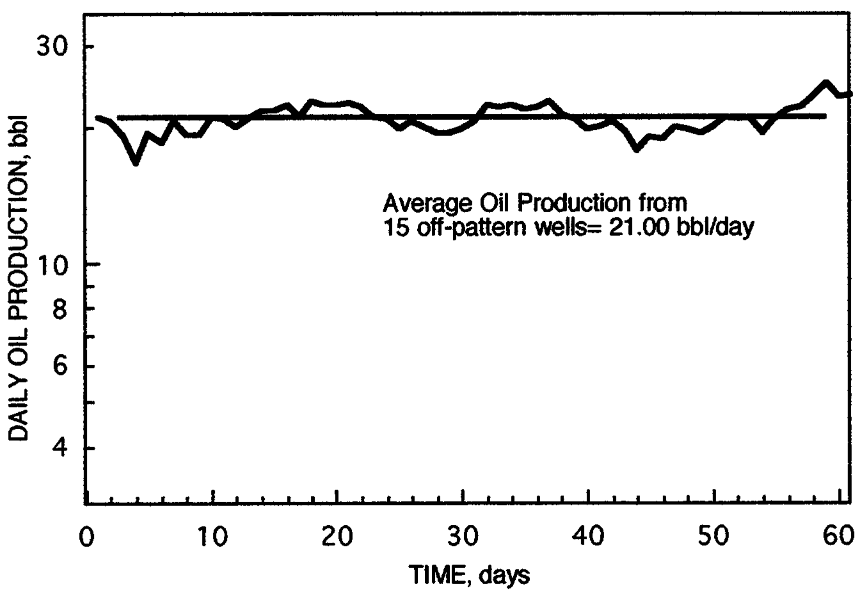

Figure 18. Baseline Production - 15 Unit Wells.

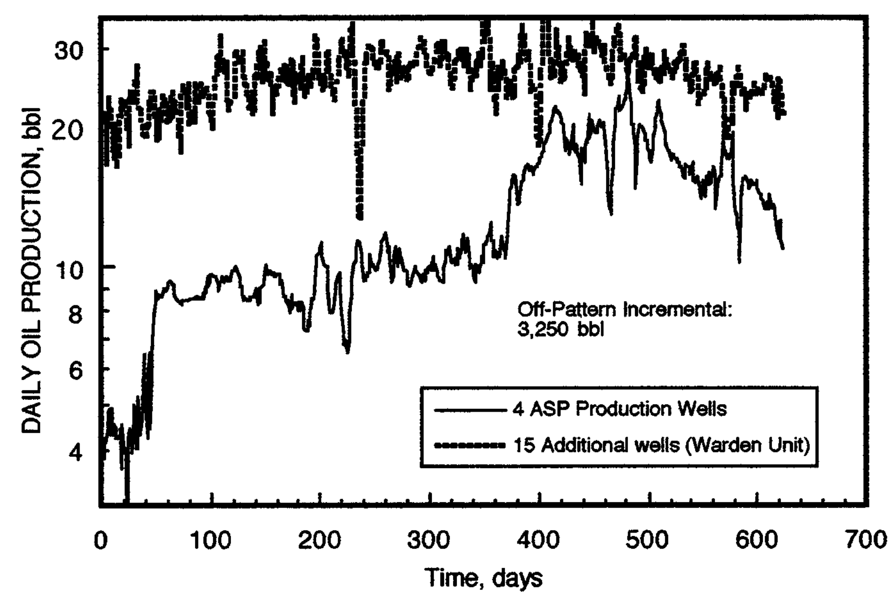

Figure 19. Oil Production from Warden Unit.

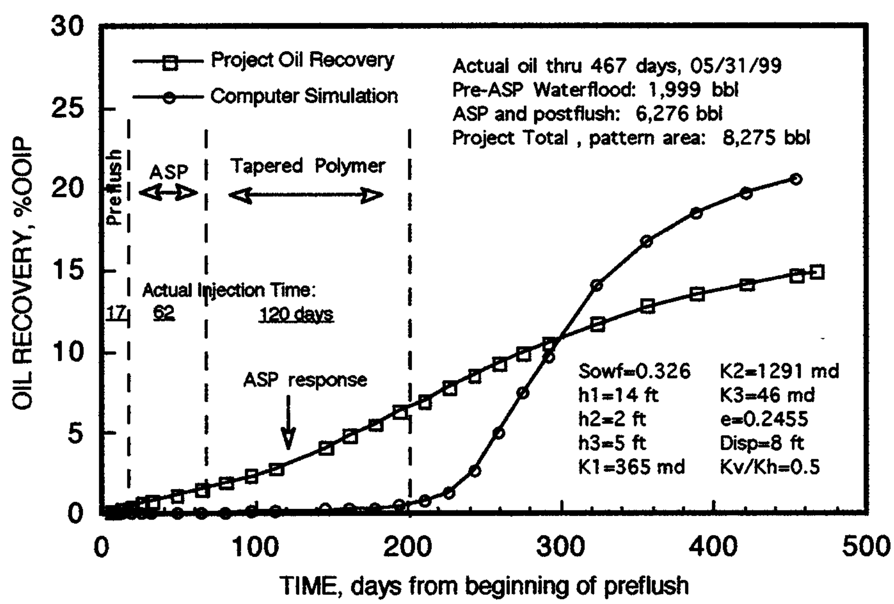

Figure 20. Comparison of Simulated and Actual Production.

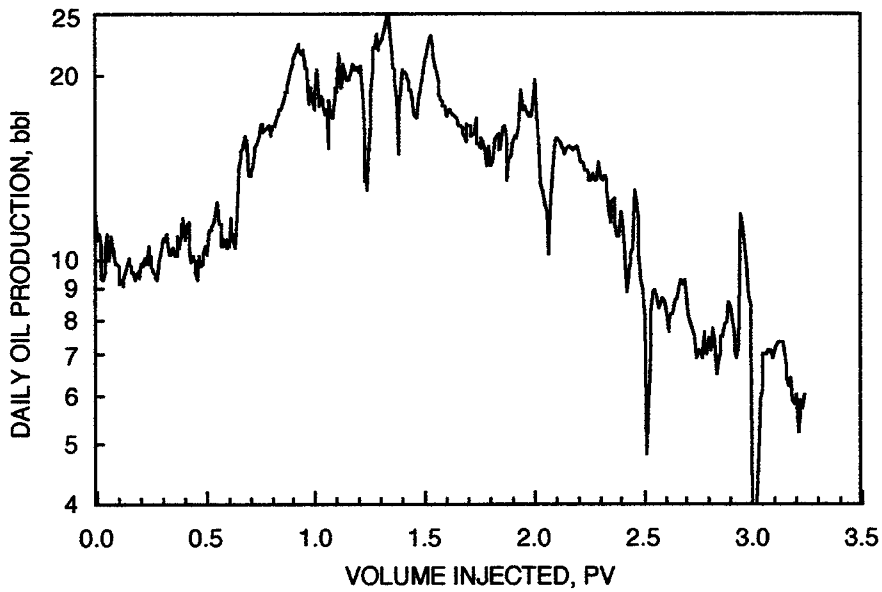

Figure 21. Oil Production from ASP Pattern Wells .